Southern Power
600 North 18th Street
Birmingham, Alabama 35203-2206

205-257-6720

SOUTHERN POWER
A SOUTHERN COMPANY

February 18, 2014

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Application for a Prevention of Significant Deterioration Air Quality Permit for Greenhouse Gas Emissions;
Nacogdoches Power Electric Generating Facility
Cushing, Nacogdoches County, Texas

Mr. Robinson:

Southern Power Company (SPC) is hereby submitting this application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for the construction of a new natural gas-fired simple cycle combustion turbine at the Nacogdoches Power Facility near Cushing, Nacogdoches County, Texas. The combustion turbine will be owned by SPC-Southern Power Company, but operations personnel for the Nacogdoches Power, LLC, biomass facility will serve the combustion turbine site as well. The state/PSD application for non-greenhouse gas emissions was submitted to the Texas Commission on Environmental Quality (TCEQ) on January 15, 2014.

General information for the application is provided on the TCEQ Form PI-1 - General Application for Air Preconstruction Permit and Amendments. The U.S. Environmental Protection Agency's (EPA) document entitled *"PSD and Title V Permitting Guidance For Greenhouse Gases", dated November 2010 and March 2011,* was utilized as a guide for preparation of the attached application.

SPC is committed to working closely with EPA Region 6 to get the application review completed as expeditiously as possible. We will be contacting your staff soon after submittal of this application to arrange a meeting to review the application and answer any questions that your team may have developed after initially reading our application.

Should you have any questions regarding this application, please contact Kelli McCullough at kamccull@southernco.com or by telephone at (205) 257-6720.

Sincerely,

Susan Comensky

Susan Comensky
Vice President, External & Regulatory Affairs

Enclosure

cc: Mr. Mike Wilson, P.E., Director, Air Permits Division, TCEQ

Mr. Edward Rapier, P.E., Zephyr Environmental Corporation

PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS PERMIT APPLICATION FOR SOUTHERN POWER COMPANY FOR ONE SIMPLE-CYCLE COMBUSTION TURBINE UNIT AT THE NACOGDOCHES POWER ELECTRIC GENERATING PLANT NACOGDOCHES COUNTY, TEXAS

SUBMITTED TO:

ENVIRONMENTAL PROTECTION AGENCY
REGION 6
MULTIMEDIA PLANNING AND PERMITTING DIVISION
FOUNTAIN PLACE 12TH FLOOR, SUITE 1200
1445 ROSS AVENUE
DALLAS, TEXAS 75202-2733

SUBMITTED BY:

SOUTHERN POWER COMPANY
600 NORTH 18TH STREET
BIRMINGHAM, ALABAMA 35203

PREPARED BY:

ZEPHYR ENVIRONMENTAL CORPORATION
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

FEBRUARY, 2014

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1.0 INTRODUCTION

In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how Prevention of Significant Deterioration (PSD) preconstruction and Title V permit programs would be applied to greenhouse gas (GHG) emissions from stationary sources, including power plants. Currently, in accordance with the Tailoring Rule, new sources that have the potential to emit 100,000 tons per year or more of GHGs, new sources that are major for PSD for non-GHG pollutants and that have the potential to emit 75,000 tons per year or more of GHGs, and existing major sources that perform a project that increases GHG emissions over 75,000 tons per year or more must go through the PSD permitting process and install the best available control technology (BACT) for GHGs.

On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas until Texas submits the required SIP revision for GHG permitting and it is approved by EPA. PSD permitting for the non-GHG PSD pollutants continues to be regulated by the Texas Commission on Environmental Quality (TCEQ).

On May 21, 2013, the Texas Legislature passed House Bill 788, and the Governor signed it into law on June 14, 2013. This new law directs the TCEQ to adopt rules to authorize GHG emissions through state issued permits. HB 788 contemplates a transitioning of applications from EPA to TCEQ, which will be the subject of coordination between EPA and TCEQ in the coming weeks and months, and this application likely will be transitioned back to TCEQ as a part of that process. Since the transition of permitting authority back to TCEQ will take some time, however, this application is being submitted to EPA for initial processing.

Note that the State and PSD air permit application for non-GHG pollutants was submitted to the TCEQ on January 15, 2014.

Southern Power Company (SPC) proposes to construct a peaking unit combustion turbine at the Nacogdoches Power Electric Generating Plant, located approximately 1 mile northeast of Sacul, Texas, in Nacogdoches County. The project consists of one natural gas-fired, simple-cycle combustion turbine generating unit (CTG) and associated support facilities. The combustion turbine planned for the project is a Siemens F5 model. This model has a nominal maximum gross electric power output of approximately 232 MW. The new CTG will operate as a peaking unit and will be limited to 2,500 hours per year of operation.

The proposed project triggers PSD review for GHG regulated pollutants because it is located at an existing major stationary source and estimated potential emissions increases will total more than 75,000 tons/yr of CO_2e as well as more than 0 tons per year of any one greenhouse gas on a mass basis. Included in this application are a project scope description, GHG potential emissions calculations, and a GHG BACT analysis.

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Southern Power Company		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Susan Comensky		
Title: VP of External and Regulatory Affairs		
Mailing Address: PO Box 2641, Bin 15N-8198		
City: Birmingham	State: AL	ZIP Code: 35203-2206
Telephone No.: 205-257-2098	Fax No.:	E-mail Address: scomensk@southernco.com
C. Technical Contact Name: Kelli McCullough		
Title: Environmental Engineer		
Company Name: Southern Company Services, Inc.		
Mailing Address: 600 North 18th Street, Bin #14N-8195		
City: Birmingham	State: AL	ZIP Code: 35203
Telephone No.: 205-257-6720	Fax No.:	E-mail Address: kamccull@southernco.com
D. Site Name: Nacogdoches Generating Facility		
E. Area Name/Type of Facility: Electric Generating Facility		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Electric Power Generation		
Principal Standard Industrial Classification Code (SIC): 4911		
Principal North American Industry Classification System (NAICS): 221112		
G. Projected Start of Construction Date: TBD		
Projected Start of Operation Date: TBD		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 499 County Road 988		
City/Town: Cushing	County: Nacogdoches	ZIP Code: 75760
Latitude (nearest second): 31° 50’ 4.7” North	Longitude (nearest second): 94° 54’ 16.5” West	

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility): NA-A003-C	
J.	Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☐ YES ☒ NO
K.	Customer Reference Number (CN): CN602742496	
L.	Regulated Entity Number (RN): RN103219127	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: 2	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Hon. Robert Nichols		District No.: 3
State Representative: Hon. Travis Clardy		District No.: 11
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested. ☐ Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation	
B.	Permit Number (if existing): 77679, PSDTX1061	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* ☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit ☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source ☐ Other:	
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III.	**Type of Permit Action Requested *(continued)***	
E.	Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0	☐ YES ☒ NO
1.	Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:		
City:	County:	ZIP Code:
2.	Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:		
City:	County:	ZIP Code:
3.	Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.	☐ YES ☐ NO
4.	Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?	☐ YES ☐ NO
F.	Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.	
List:		
G.	Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.	☒ YES ☐ NO
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).	☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): O3455		
1.	Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.	
☐ FOP Significant Revision	☐ FOP Minor	☒ Application for an FOP Revision
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP
☐ To be Determined		☐ None

III. Type of Permit Action Requested *(continued)*		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*		
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***		
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☒ SOP Issued	☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability		
A. Is this a new permit application or a change of location application?		☐ YES ☒ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.		☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?		☒ YES ☐ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?		☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.		
1. Is there any change in character of emissions in this application?		☐ YES ☒ NO
2. Is there a new air contaminant in this application?		☐ YES ☒ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?		☐ YES ☒ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***		
Volatile Organic Compounds (VOC): 97 tpy		
Sulfur Dioxide (SO2): 3 tpy		
Carbon Monoxide (CO): 829 tpy		
Nitrogen Oxides (NOx): 109 tpy		
Particulate Matter (PM): 13 tpy		
PM 10 microns or less (PM10): 13 tpy		
PM 2.5 microns or less (PM2.5): 13 tpy		
Lead (Pb):		
Hazardous Air Pollutants (HAPs): <10 single HAP, < 25 total HAP		
Other speciated air contaminants not listed above: 0.7 tons H2SO4; 319,827 tons CO2e		

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Kelli McCullough		
Title: Environmental Engineer		
Mailing Address: 600 N 18th St, Bin 14N-8195, PO Box 2641		
City: Birmingham	State: AL	ZIP Code: 35291
B. Name of the Public Place: Judy B. McDonald Public Library		
Physical Address *(No P.O. Boxes)*: 1112 North Street		
City: Nacogdoches	County: Nacogdoches	ZIP Code: 75961
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Judge Joe English		
Mailing Address: 101 W. Main, Suite 170		
City: Nacogdoches	State: TX	ZIP Code: 75961
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive: Mayor Don B. Richards		
Mailing Address: P.O. Box 365		
City: Cushing	State: TX	ZIP Code: 75760-0365
Name of the Indian Governing Body: N/A		
Mailing Address:		
City:	State:	ZIP Code:

V. Public Notice Information *(complete if applicable) (continued)*	
C. Concrete Batch Plants, PSD, and Nonattainment Permits	
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s): N/A	
D. Bilingual Notice	
Is a bilingual program required by the Texas Education Code in the School District?	☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☒ YES ☐ NO
If Yes, list which languages are required by the bilingual program?	Spanish
VI. Small Business Classification *(Required)*	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII. Technical Information	
A. The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1. ☒ Current Area Map	
2. ☒ Plot Plan	
3. ☒ Existing Authorizations	
4. ☒ Process Flow Diagram	
5. ☒ Process Description	
6. ☒ Maximum Emissions Data and Calculations	
7. ☒ Air Permit Application Tables	
a. ☒ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b. ☐ Table 2 (Form 10155) entitled, Material Balance	
c. ☒ Other equipment, process or control device tables	
B. Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

VII.	**Technical Information**		
C.	Maximum Operating Schedule:		
Hour(s): 24 hr/day	Day(s): 7 day/week	Week(s): 52 week/year	Year(s): 2,500 hr/year
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?		☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
E.	Does this application involve any air contaminants for which a disaster review is required?		☐ YES ☒ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?		☐ YES ☒ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*		
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?		☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?		☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?		☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?		☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*		
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?		☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?		☐ YES ☒ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number:		Fee Amount:
Paid online?		☐ YES ☐ NO
Company name on check:		
Is a copy of the check or money order attached to the original submittal of this application?		☐ YES ☐ NO ☒ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☐ YES ☐ NO ☒ N/A

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

XII. Delinquent Fees and Penalties
This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Susan Comensky
Signature: Susan Comensky *Original Signature Required*
Date: 2.18.14

2.0 PROJECT SCOPE

2.1 INTRODUCTION

SPC is seeking authorization to construct and operate one natural gas-fired simple-cycle combustion turbine generator (CTG) at the Nacogdoches Power Electric Generating Plant (NPEGP), in Nacogdoches County, Texas. SPC has determined that a simple-cycle unit producing a nominal maximum gross electric power output of approximately 232 MW is needed to reliably and economically meet the peak energy needs of SPC's customers that will be served by this project. In addition, to most effectively meet these needs, the simple-cycle unit must be capable of operating in a range of modes, which includes the use of inlet evaporative cooling. The power generating equipment and ancillary equipment that will be potential sources of GHG emissions at the site are summarized below:

- One natural gas-fired simple-cycle combustion turbine;
- Natural gas fuel supply dew-point heater;
- Natural gas piping and handling and metering equipment; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6). Although the equipment containing SF_6 is designed to be leak proof, and therefore is not expected to be a source of emissions, SPC has calculated potential SF_6 emissions to be conservative.

A process flow diagram is included at the end of this section.

Pipeline-quality natural gas is chosen as the only fuel for the combustion turbine due to local availability of this fuel and the infrastructure to support delivery of this fuel to the facility in adequate volume and pressure.

The simple-cycle unit will fulfill the obligations of SPC by reliably and economically meeting the needs of its customers while meeting applicable environmental requirements.

2.2 COMBUSTION TURBINE GENERATOR (CTG)

The CTG burns pipeline-quality natural gas to rotate an electrical generator. The main components of the CTG consist of a compressor, combustor, turbine, and generator. The compressor pressurizes the inlet combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the expansion turbine where the gases expand across the turbine blades, which generates torque that drives a shaft to power an electric generator. The temperature of the inlet air to the CTG proposed for NPEGP will at times be lowered using evaporative cooling to increase the mass air flow through the turbine and achieve maximum turbine power output on days with warm to hot ambient conditions.

The exhaust gases from the combustion turbine will be directed to a stack and then to the atmosphere. The emission point number (EPN) for the combustion turbine unit is given as CTG1-STK.

The combustion turbine generator will produce electricity for sale to the Electric Reliability Council of Texas power grid. The Siemens Model F5 simple-cycle unit has been selected for this site and will produce a nominal maximum gross electric power output of approximately 232 MW at site conditions. The unit load will vary to respond to changes in system power requirements and/or stability. The typical operating range of the Siemens F5 will be between 50 percent and 100 percent of base load.

Startup and shutdown of the proposed simple-cycle unit is part of the regularly scheduled operations at the facility. Startup and shutdown periods for the combustion turbine are defined by monitored operating conditions. For the combustion turbine, a startup is defined as the period from when an initial flame detection signal is recorded in the plant's Data Acquisition and Handling System (DAHS) and ends with the achievement of the minimum output level (approximately 50 percent) at which the unit has been demonstrated by a CEMS or during a compliance test to have met the normal steady state operating emission limits. The shutdown period begins when the combustion turbine output drops below the start-up end point as indicated in the previous sentence, and ends when the flame detection signal is no longer recorded in the plant's DAHS.

2.3 NATURAL GAS-FIRED DEW-POINT HEATER

An approximately 2.75 MMBtu/hr natural gas-fired, dew-point heater will be utilized for the proposed project. This heater (EPN HTR1) will heat the natural gas prior to its use as fuel for the combustion turbine in order to prevent condensed liquids in the natural gas from damaging the combustor sections of the turbine. The heater will be in operation any time the combustion turbine is firing natural gas.

2.4 NATURAL GAS PIPING FUGITIVES

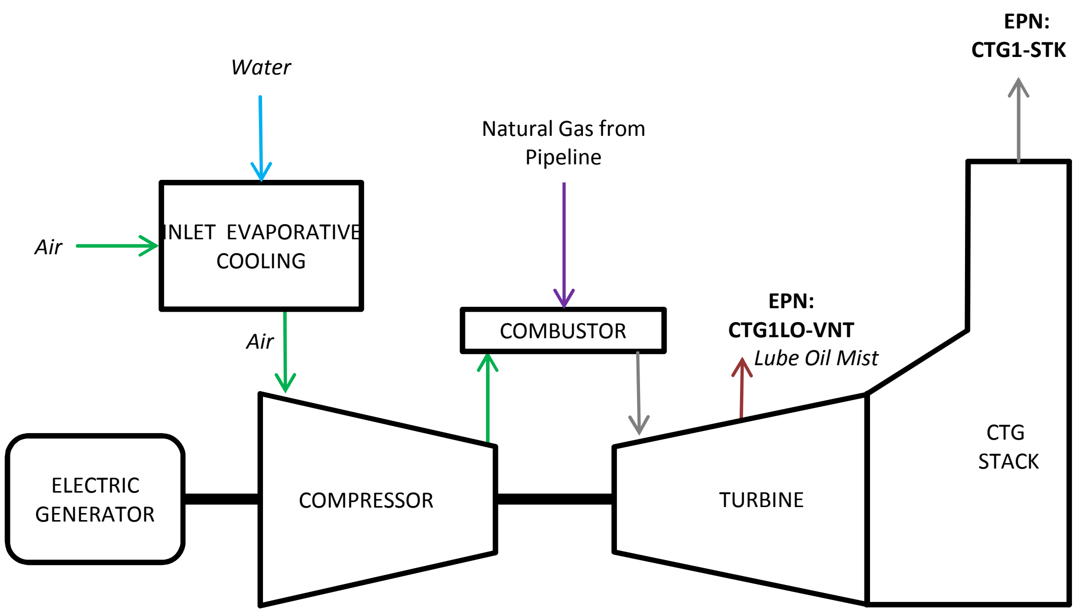
Natural gas will be delivered to the site via pipeline and then metered and piped to the combustion turbine. Fugitive emissions from the gas piping components associated with the new CTG unit will include emissions of methane (CH_4) and carbon dioxide (CO_2). Fugitive emissions of natural gas are designated as EPN VOC-FUG.

2.5 ELECTRICAL EQUIPMENT INSULATED WITH SULFUR HEXAFLUORIDE (SF_6)

The generator circuit breakers associated with the proposed unit will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 150 lbs. of SF_6. Although fugitive emissions of SF_6

are not expected because the equipment is designed to be leak free, to be conservative SF_6 emissions are included in this application.

The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

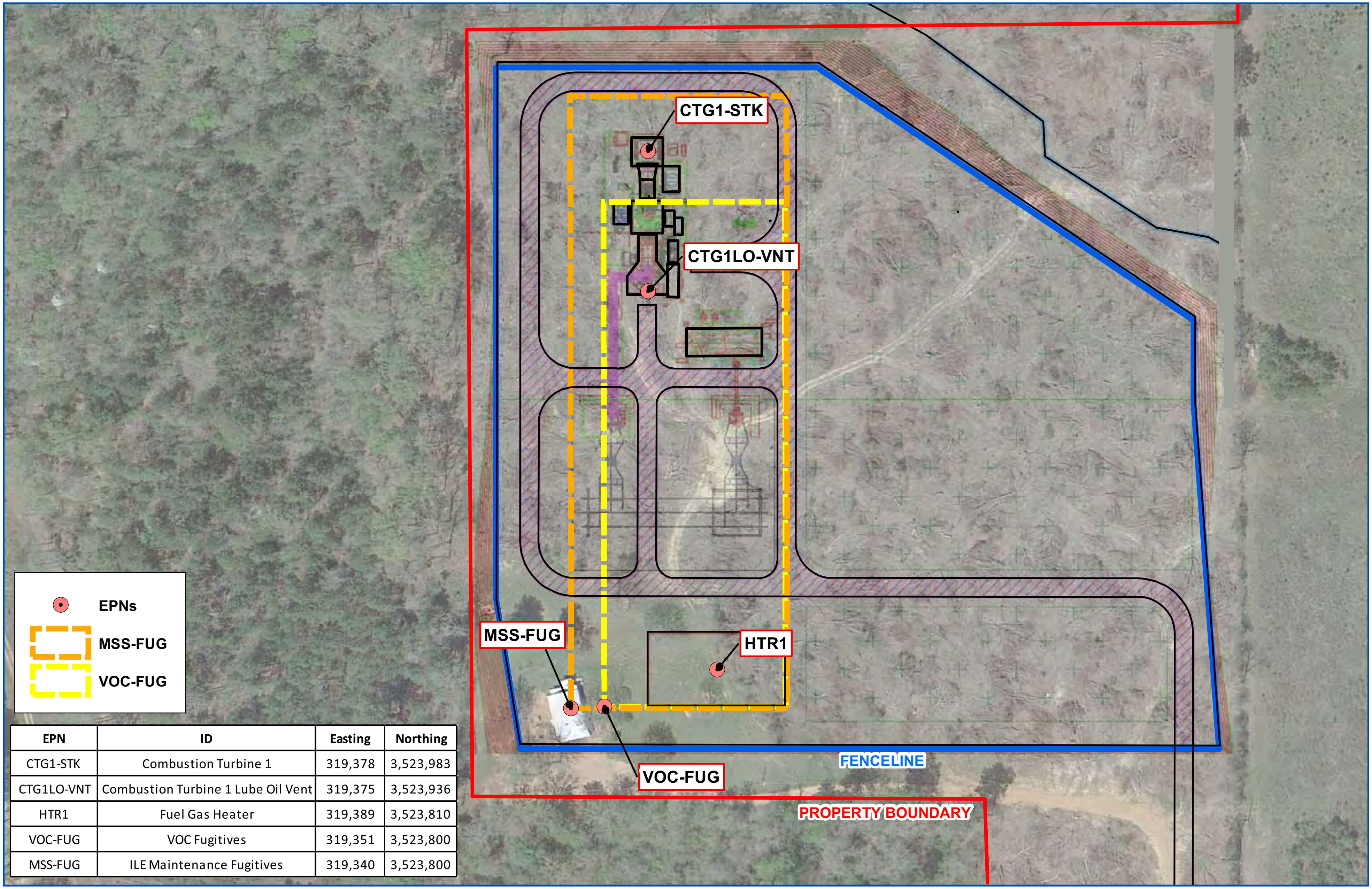


COMBUSTION TURBINE GENERATOR

MISCELLANEOUS EPNs:

HTR1 - Fuel Gas Heater
VOC-FUG - VOC Fugitives
SF6-FUG - SF6 Fugitives
MSS-FUG - ILE Maintenance Fugitives

Nacogdoches Power Electric Generating Plant, Simple Cycle Peaking Gas Turbine			FIGURE VII.A.4 PROCESS FLOW DIAGRAM		
Permit Application			Filename: PFD		
zephyr	Drawn by: B.Breeze	Checked by: E. Rapier	Project No.: 13391	Date: 1/13/2014	Sheet: 1 of 1



EPN	ID	Easting	Northing
CTG1-STK	Combustion Turbine 1	319,378	3,523,983
CTG1LO-VNT	Combustion Turbine 1 Lube Oil Vent	319,375	3,523,936
HTR1	Fuel Gas Heater	319,389	3,523,810
VOC-FUG	VOC Fugitives	319,351	3,523,800
MSS-FUG	ILE Maintenance Fugitives	319,340	3,523,800

Map Sources: Google Earth Pro Image 03.26.13 Datum: GCS NAD 83, UTM Zone 15

N

Scale 1:1,750

0 50 100 Meters

0 150 300 Feet

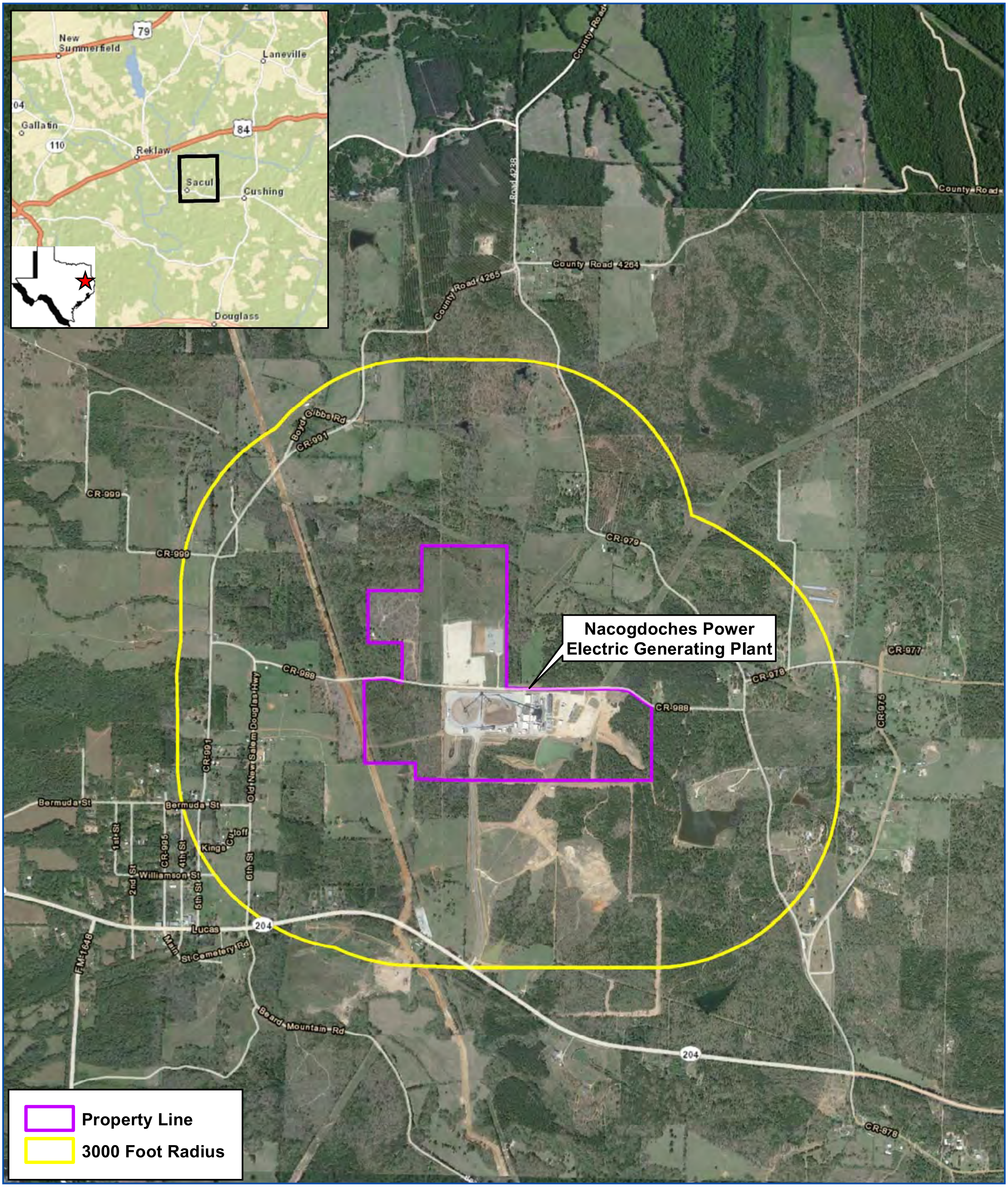
zephyr

PLOT PLAN

Nacogdoches Power Electric Generating Plant
Nacogdoches County, Texas

H:\Southern Company\013391 Nacogdoches Power New Turbine\GIS

Drafted by:	Reviewed By:	Project No.:	Date:
J. Knowles	E. Rapier	013391	12.17.2013



Map Sources: Bing Hybrid Basemap,Google Earth Pro Image 03.26.13, Datum: WGS 84

N

Scale 1:24,000

0 0.5 1 Kilometers

0 0.5 1 Miles

zephyr

AREA MAP

Nacogdoches Power Electric Generating Plant
Nacogdoches County, Texas

..\Southern Company\013391 Nacogdoches Power New Turbine\GIS\PDF

Drafted by:	Reviewed By:	Project No.:	Date:
J. Knowles	E. Rapier	013391.004	12.17.2013

3.0 GHG POTENTIAL EMISSION CALCULATIONS

PSD applicability to GHG emissions from a source is based on CO_2 equivalent (CO_2e) emissions as well as its GHG mass emissions. CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for their global warming potential (GWP), obtained from Table A-1 of the Mandatory Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98, Subpart A). Consequently, when determining the applicability of PSD to GHGs, there is a two-part applicability process that evaluates both:

- The sum of the CO_2e emissions in TPY of the six GHGs, in order to determine whether the source's emissions are a regulated NSR pollutant; and, if so

- The sum of the mass emissions in TPY of the six GHGs, in order to determine whether the source's emissions trigger the PSD major source or modification thresholds.

GHG species directly emitted by the combustion of natural gas from this project are CO_2, nitrous oxide (N_2O), and CH_4. Although emissions are not expected, potential emissions of sulfur hexafluoride (SF_6) are also accounted for in the calculations. Two other GHG species – hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) – have no potential to be emitted.

GHGs are generated from combustion of carbon-containing fuel (e.g., CO_2), the incomplete combustion of fuel (CH_4), or the partial reaction of nitrogen compounds within the fuel or air during the combustion process (N_2O). CO_2 is the predominant GHG emission, with methane and nitrous oxide being emitted in trace quantities. The production rate of these species depends on the fuel composition, the details of the combustion conditions, and net thermal efficiency of the generating unit. Plant-wide GHG emissions are summarized on Table 3-1.

3.1 GHG EMISSIONS FROM SIMPLE-CYCLE COMBUSTION TURBINE

GHG emissions for the combustion turbine are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart D – Electric Generation.[1] Annual CO_2 emissions are calculated using the methodology in equation G-4 of the Acid Rain Rules.[2]

$$W_{CO_2} = \left(\frac{F_C \times H \times U_f \times MW_{CO_2}}{2000} \right) \qquad (Eq.\ G\text{–}4)$$

Where:

W_{CO2} = CO_2 emitted from combustion, tons/yr

[1]40 CFR 98, Subpart D – *Electricity Generation*.
[2]40 CFR. 75, Appendix G – *Determination of CO_2 Emissions.*

MW_{CO2} = Molecular weight of carbon dioxide, 44.0 lb/lb-mole

F_c = Carbon based F-factor, 1,040 scf/MMBtu for natural gas

H = Annual heat input in MMBtu

U_f = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F.

Emissions of CH_4 and N_2O are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[3] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.

CO_2 emissions from the associated natural gas-fired heater are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[4] CH_4 and N_2O emissions from the heater are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[5]

Calculations of potential GHG emissions from the simple-cycle turbine are presented on Tables 3-2 and 3-3 and calculations of potential GHG emissions from the associated natural gas heater are presented on Table 3-4.

3.2 GHG EMISSIONS FROM NATURAL GAS PIPING FUGITIVES AND NATURAL GAS MAINTENANCE AND STARTUP/SHUTDOWN RELATED RELEASES

GHG emission calculations for natural gas/fuel gas piping component fugitive emissions are based on emission factors from Table W-1A of the “2012 Technical Corrections, Clarifying and Other Amendments to the Greenhouse Gas Reporting Rule, and Confidentiality Determinations for Certain Data Elements of the Fluorinated Gas Source Category” which was signed on August 3, 2012[6]. The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis. Since the CH_4 and CO_2 content of natural gas is variable, the concentrations of CH_4 and CO_2 from the typical natural gas analysis are used as an estimate. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[7] These factors are applied to a conservative fugitive component count to calculate the potential GHG emissions.

GHG emission calculations for releases of natural gas related to piping maintenance and turbine startup/shutdowns are calculated using the same CH_4 and CO_2 concentrations as natural gas/fuel gas piping fugitives.

[3] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR. 98, Subpt. C, Tbl. C-2
[4] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 CFR. 98, Subpt. C, Tbl. C-1
[5] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR. 98, Subpt. C, Tbl. C-2
[6] http://www.epa.gov/ghgreporting/reporters/notices/corrections.html
[7] *Global Warming Potentials*, 40 CFR. Pt. 98, Subpt. A, Tbl. A-1

Calculations of potential GHG emissions from natural gas piping fugitives are presented on Table 3-5. Calculations of GHG emissions from releases of natural gas related to piping maintenance and turbine maintenance and startup/shutdown activities are presented on Table 3-6.

3.3 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF_6

SF_6 emissions from the new generator circuit breaker and yard breaker associated with the proposed unit are calculated using a conservative SF_6 annual leak rate of 0.5% by weight. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[8]

Calculations of potential GHG emissions from electrical equipment insulated with SF_6 are presented on Table 3-7.

[8]*Global Warming Potentials*, 40 CFR. Pt. 98, Subpt. A, Tbl. A-1

Table 3-1
Annual GHG Emission Summary
Nacogdoches Power Electric Generating Plant

Name	EPN	GHG Mass Emissions ton/yr	CO_2e ton/yr
Combustion Turbine 1	CTG1-STK	318,841	319,158
Fuel Gas Heater	HTR1	402	402
VOC Fugitives	VOC-FUG	10	254
ILE Maintenance Fugitives	MSS-FUG	0.14	3
SF_6 Insulated Equipment	SF6-FUG	0.0004	9
Project Total Emissions:		**319,253**	**319,827**

Table 3-2

GHG Emission Calculations - Siemens F5 Simple-Cycle Turbine (Annual)

Nacogdoches Power Electric Generating Plant

EPN	Average Heat Input[1] (MMBtu/hr)	Annual Heat Input[2] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[3]	GHG Mass Emissions[4] (tpy)	Global Warming Potential[5]	CO_2e (tpy)
CTG1-STK	2,146	5,365,000	CO_2	118.86	318,834	1	318,834
			CH_4	2.2E-03	5.9	25	147.8
			N_2O	2.2E-04	0.6	298	176.2
				Total:	**318,841**		**319,158**

<u>*Note*</u>

1. *The average heat input is based on the HHV heat input at 100% load at 95 ^oF ambient temperature.*
2. *Annual heat input based on 2,500 hours per year operation.*
3. *CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
4. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 emitted from combustion, tons/yr

F_c = Carbon based F-factor,1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 ^oF

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lb-mole

5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-3
GHG Emission Calculations - Siemens F5 Simple-Cycle Turbine (Hourly)
Nacogdoches Power Electric Generating Plant

Max Hourly GHG Emissions From Siemens F5 Turbine

EPN	Max Hourly Heat Input[1] (MMBtu/hr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions[3] (ton/hr)	Global Warming Potential[4]	CO_2e (ton/hr)
CTG1-STK	2,276.0	CO_2	118.86	135	1	135
		CH_4	2.2E-03	0.0025	25	0.0627
		N_2O	2.2E-04	0.0003	298	0.0748
			Total:	**135**		**135**

Startup/Shutdown Hourly GHG Emissions Related to the Siemens F5 Turbine

EPN	Heat Input During Startup[1] (MMBtu/hr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions[3] (ton/hr)	Global Warming Potential[4]	CO_2e (ton/hr)
CTG1-STK	1,253	CO_2	118.86	74	1	74
		CH_4	2.2E-03	0.0014	25	0.0345
		N_2O	2.2E-04	0.0001	298	0.0412
HTR1	2.75	CO_2	116.89	0	1	0
		CH_4	2.2E-03	0.00000	25	0.0001
		N_2O	2.2E-04	0.000000	298	0.0001
			Total:	**75**		**75**

Note

1. *The following hourly heat input data are from the Design Basis document for the Siemens F5 unit*

	Operating Mode	Site Condition	Turbine Heat Input MMBtu/hr, HHV
Maximum Hourly Heat Input	Base Load, 95 °F Ambient, Evaporative Cooler on	Summer	2,276
Maximum Hourly Heat Input During Startup	-	-	1,253

2. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.
3. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

W_{CO2} = (Fc x H x U_f X MW_{CO2})/2000

W_{CO2} = CO_2 emitted from combustion, tons/hr

Fc = Carbon based F-factor,1040 scf/MMBtu

H = Heat Input (MMBtu/hr)

U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 ^oF

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lb-mole

4. *Global Warming Potential factors from Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-4
GHG Emission Calculations - Natural Gas Heater
Nacogdoches Power Electric Generating Plant

EPN	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
HTR1	6,875	CO_2	116.89	402	1	402
		CH_4	2.2E-03	0.01	25	0.2
		N_2O	2.2E-04	0.001	298	0.2
			Total:	**402**		**402**

Note

1. *Annual fuel use and heating value of natural gas from Table A-6 State/PSD air permit application*
2. *Factors based on Table C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-5
GHG Emission Calculations - Natural Gas Piping Fugitives
Nacogdoches Power Electric Generating Plant

EPN	Source Type	Fluid State	Count	Emission Factor[1] (scf/hr/comp)	CO_2[2] (tpy)	Methane[3] (tpy)	**Total (tpy)**
VOC-FUG	Valves	Gas/Vapor	300	0.121	0.096	6.357	
	Flanges	Gas/Vapor	1,200	0.017	0.054	3.573	
	Relief Valves	Gas/Vapor	5	0.193	0.003	0.169	
	Sampling Connections	Gas/Vapor	10	0.031	0.0008	0.0543	
	Compressors	Gas/Vapor	3	0.003	0.000024	0.00158	
GHG Mass-Based Emissions					0.154	10.15	**10.31**
Global Warming Potential[4]					1	25	
CO_2e Emissions					0.154	253.86	**254.02**

Note

1. *Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting published in the May 21, 2012 Technical Corrections*
2. *CO_2 emissions based on vol% of CO_2 in natural gas* 0.53%
3. *CH_4 emissions based on vol% of CH_4 in natural gas* 96.0%
4. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

300 valves	0.121 scf gas	0.0053 scf CO2	lbmole	44 lb CO_2	8760 hr	ton =	0.096 ton/yr
	hr * valve	scf gas	385 scf	lbmole	yr	2000 lb	

TABLE 3-6

GHG Emission Calculations - Gaseous Fuel Venting During Turbine Shutdown/Maintenance and Small Equipment and Fugitive Component Repair/Replacement

Nacogdoches Power Electric Generating Plant

Location	Initial Conditions			Final Conditions			Annual Emissions		**Total**
	Volume[1] (ft^3)	Press. (psig)	Temp. (°F)	Press. (psig)	Temp. (°F)	Volume[2] (scf)	CO_2[3] (tpy)	CH_4[4] (tpy)	**(tpy)**
Turbine Fuel Line Shutdown/Maintenance	138	600	50	0	68	6,710	0.0020	0.13	
Small Equipment/Fugitive Component Repair/Replacement	6.7	50	50	0	68	31	0.00001	0.00061	
GHG Mass-Based Emissions							0.0020	0.1344	**0.14**
Global Warming Potential[5]							1	25	
CO_2e Emissions							0.0020	3.4	**3.4**

1. Initial volume is calculated by multpilying the crossectional area by the length of pipe using the following formula: V= pi * [(diameter in inches/12)/2]^2 * length in feet = ft^3

2. Final volume calculated using ideal gas law [(PV/ZT)$_i$ = (PV/ZT)$_f$]. $V_f = V_i (P_i/P_f) (T_f/T_i) (Z_f/Z_i)$, where Z is estimated using the following equation: $Z = 0.9994 - 0.0002P + 3E\text{-}08P^2$.

3. *CO_2 emissions based on vol% of CO_2 in natural gas* 0.53% from natural gas analysis
4. *CH_4 emissions based on vol% of CH_4 in natural gas* 96.0% from natural gas analysis
5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

6710 scf Nat Gas	0.005 scf CO2	lbmole	44 lb CO_2	ton =	=	0.0020	ton/yr CO_2
yr	scf Nat Gas	385 scf	lbmole	2000 lb			

Table 3-7

GHG Emission Calculations - Electrical Equipment Insulated With SF_6

Nacogdoches Power Electric Generating Plant

Assumptions

Insulated circuit breaker SF_6 capacity:	150	lb
Estimated annual SF_6 leak rate:	0.5%	by weight
Estimated annual SF_6 mass emission rate:	0.0004	ton/yr
Global Warming Potential[1]:	22,800	
Estimated annual CO_2e emission rate:	8.6	ton/yr

Example calculation:

150 lb	0.5 % by weight	ton	=	0.0004	ton/yr SF_6
yr		2000 lb			

0.0004 ton SF6	22800 GWP	=	8.6	ton/yr CO_2
yr				

<u>*Note*</u>

Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

4.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

This project involves the construction of a new unit at an existing site. Based on the GHG potential emission calculations provided above, this project will emit GHG emissions (sum of six GHG) in excess of the applicable 75,000 tons per year CO_2e and zero tpy mass basis PSD permitting thresholds established by the Tailoring Rule. The existing units at the site have been in operation for less than two years and there are no contemporaneous reductions of emissions. Therefore, the GHG emissions increases associated with this project will trigger PSD permitting under the Tailoring Rule as shown in the table below.

Regulated PSD Pollutants	Permitting Threshold (tpy)	Project Emissions (tpy)	Contemporaneous Emissions (tpy)	PSD?
One CT Unit and Associated Ancillary Equipment				
GHG (CO_2e)	>75,000	319,827	>75,000	YES
GHG (mass)	> 0	319,253	>75,000	YES

The potential GHG emissions are documented on the attached TCEQ PSD netting tables: Table 1F and Table 2F. Also included in Appendix A is the “GHG Applicability Flow Chart – Modified Sources” from the *PSD and Title V Permitting Guidance for Greenhouse Gases.*

In accordance with this PSD applicability determination, the top-down GHG BACT analyses are provided in this application for all sources of GHGs for the proposed project.

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

TCEQ

Permit No.:	77679, PSDTX1061, and HAP55	Application Submittal Date:	02/19/2014
Company	Nacogdoches Power LLC		
RN:	RN103219127	Facility Location:	
City:	Sacul	County:	Nacogdoches
Permit Unit I.D.:	CTG1-STK	Permit Name:	Simple Cycle Turbine
Permit Activity:	☐ New Source	☑ Modification	
Project or Process Description:	Construction of a simple-cycle combustion turbine unit		

Complete for all pollutants with a project emission increase.	POLLUTANTS						
	Ozone		CO	SO_2	PM	Other[1]	
	NOx	VOC				GHG	CO_2e
Nonattainment?						No	No
PSD?						Yes	Yes
Existing site PTE (tpy)	**This form for GHG only**					>75K	>75K
Proposed project increases (tpy from 2F)[2]						319,253	319,827
Is the existing site a major source?						Yes	Yes
If not, is the project a major source by itself?							
If site is major, is project increase significant?						Yes	Yes
If netting required, estimated start of construction:							
5 years prior to start of construction:							contemporaneous
Estimated start of operation:							period
Net contemporaneous change, including proposed project, from Table 3F (tpy) [3]						>75K	>75K
Major FNSR applicable?						Yes	Yes

1. Other PSD pollutants
2. Sum of proposed emissions minus baseline emissions, increases only.
3. Since there are no contemporaneous decreases which would potentially affect PSD applicability and an impacts analysis is not required for GHG emissions, contemporaneous emission changes are not included on this table.

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

Susan Comensky	VP of External and Regulatory Affairs	2/18/2014
Signature	Title	Date

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	GHG	**Permit:**	77679, PSDTX1061, and HAP55
Baseline Period:	N/A **to** N/A		

Affected or Modified Facilities[2]	FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B - A)[6]	Correction[7]	Project Increase[8]
1	CTG1	CTG1-STK	77679, PSDTX1061, and HAP55	0.00	0.00	318,841		318,841		318,841
2	HTR1	HTR1	77679, PSDTX1061, and HAP55	0.00	0.00	402		402		402
3	VOC-FUG	VOC-FUG	77679, PSDTX1061, and HAP55	0.00	0.00	10		10		10
4	MSS-FUG	MSS-FUG	77679, PSDTX1061, and HAP55	0.00	0.00	0.14		0		0
5	SF6-FUG	SF6-FUG	77679, PSDTX1061, and HAP55	0.00	0.00	0.0004		0.0004		0.0004
6										
7										
8										
9										
10										
11										
12										
14										
15										
							Page Subtotal[9]			319,253

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	CO_2e	**Permit:**	77679, PSDTX1061, and HAP55
Baseline Period:	N/A **to** N/A		

					A	B				
Affected or Modified Facilities[2]	**FIN**	**EPN**	**Permit No.**	**Actual Emissions[3]**	**Baseline Emissions[4]**	**Proposed Emissions[5]**	**Projected Actual Emissions**	**Difference (B - A) [6]**	**Correction[7]**	**Project Increase[8]**
1	CTG1	CTG1-STK	77679, PSDTX1061, and HAP55	0.00	0.00	319,158		319,158		319,158
2	HTR1	HTR1	77679, PSDTX1061, and HAP55	0.00	0.00	402		402		402
3	VOC-FUG	VOC-FUG	77679, PSDTX1061, and HAP55	0.00	0.00	254		254		254
4	MSS-FUG	MSS-FUG	77679, PSDTX1061, and HAP55	0.00	0.00	3		3		3
5	SF6-FUG	SF6-FUG	77679, PSDTX1061, and HAP55	0.00	0.00	9		9		9
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
								Page Subtotal[9]		319,827

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

1. Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

EPA's PSD rules define BACT as follows:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.[9]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommends the continued use of the Agency's existing five-step "top-down" BACT process to determine BACT for GHGs.[10] In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. Once technically feasible options are identified and ranked based on control effectiveness, the permit applicant should first examine the highest-ranked ("top") option. The top-ranked option should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative is to be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this analytical process into the following five steps:

- Step 1: Identify all available control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies

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[9] 40 C.F.R. § 52.21(b)(12.)

[10] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

- Step 4: Evaluate most effective controls and document results
- Step 5: Select the BACT.

5.1 BACT FOR THE NATURAL GAS-FIRED SIMPLE-CYCLE UNIT

5.1.1 Step 1: Identify All Available Control Technologies

The options for controlling GHG emissions, including CO_2, CH_4, and N_2O, can be divided into the following categories:

- Add-on (post-combustion) controls
- Energy Efficient Processes, Practices, and Designs

5.1.1.1 Post-Combustion Controls

Carbon Capture Sequestration - (CCS)

As EPA states in its PSD and Title V Permitting Guidance for Greenhouse Gases (EPA, 2011) ("GHG BACT Guidance"), "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants...[and] should be listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources."[11]

The CCS process is defined by the Interagency Task Force on CCS as "a three-step process that includes capture and compression of CO_2 from power plants or industrial sources; transport of the captured CO_2 (usually in pipelines); and storage of that CO_2 in geologic formations, such as deep saline formations, oil and gas reservoirs, and un-mineable coal seams."[12]

There are no other potentially available post-combustion control technologies for CO_2, CH_4, or N_2O identified at this time.

5.1.1.2 Energy Efficient Processes, Practices, and Design Options for Combustion Turbines

As stated in the GHG BACT Guidance, inclusion of a combined-cycle combustion turbine design in the BACT selection process for facilities wishing to construct a natural gas-fired power generation facility is desired:

> "The first category of energy efficiency improvement options includes technologies or processes that maximize the energy efficiency of the individual emissions unit. For example, the processes that may be used in electric generating facilities have varying

[11] http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf (pg.32)
[12] http://fossil.energy.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf

> levels of energy efficiency, measured in terms of amount of heat input that is used in the process or in terms of per unit of the amount of electricity that is produced. When a permit applicant proposes to construct a facility using a less efficient boiler design, such as a pulverized coal (PC) or circulating fluidized bed (CFB) boiler using subcritical steam pressure, a BACT analysis for this source should include more efficient options such as boilers with supercritical and ultrasupercritical steam pressures. Furthermore, *combined cycle combustion turbines, which generally have higher efficiencies than simple cycle turbines, should be listed as options when an applicant proposes to construct a natural gas-fired facility.*"[13] (emphasis added).

As a result of this guidance, evaluation of a combined-cycle configuration is included.

5.1.1.2.1 Combined-Cycle Combustion Turbine Configuration

A typical simple-cycle combustion turbine consists of the following main components: Compressor Section, Combustor Section and the Expansion/Power Turbine section. The torque generated by the power turbine section rotates a generator shaft, thus producing electrical power. A simple-cycle combustion turbine can be started and reach full load in a matter of minutes. These units can also be shut down almost instantaneously. As a result, these types of units typically are utilized for peaking service. Peaking facilities are required to be dispatched quickly and frequently operate for very short durations (as short as a few minutes to several hours) before shutting down.

A combined-cycle combustion turbine configuration is quite different in design and function. Most notably, combined-cycle combustion turbines typically provide more MW capacity than simple cycle combustion turbines and are typically used to meet load demands that are intermediate to baseload in nature. Combined-cycle technology is more suitable for intermediate to baseload needs because startups of combined-cycle combustion turbines typically are measured in hours instead of minutes. Since the loads that they are required to meet are more predictable than the peaking demands, these units are started well in advance of when they are needed for intermediate or baseload demands. The intermediate load demands are typically hours to days in duration. Base-loaded facilities are typically operated for longer durations (typically several months in duration) and are generally not capable of quick starts.

In the case of NPEGP, the current need at this location is to construct a combustion turbine that would meet peaking demand requirements. Although the installation of a combined-cycle combustion turbine at this site would theoretically produce electrical power more efficiently than a simple-cycle combustion turbine, the installation of a combined-cycle facility would not be considered available for the purpose of reliably and economically meeting customer needs associated with this new unit. The fundamental business purpose of this new unit is to provide peaking electrical power, on demand, with extremely short lead times, which combined-cycle combustion turbine configurations are not equipped to do. In addition, the proposed annual operating limit of 2,500 hours and the emission limit of 319,158 tons of CO2e per year from this

[13] PSD and Title V Permitting Guidance for Greenhouse Gases (EPA, 2011), page 29

CT are characteristic of a simple cycle peaking unit and are significantly less than the operating hours and emission rates associated with combined-cycle units (typically 8,760 hours per year with a corresponding increase in annual mass emissions). This being the case, the combined-cycle combustion turbine configuration option would result in a redefinition of the source and will be excluded from any further consideration as part of this BACT process.

5.1.1.2.2 Simple-Cycle Combustion Turbine Energy Efficient Processes, Practices, and Designs

EPA Region 6 has concluded in recent greenhouse gas permitting decisions that the proposed energy efficient processes, practices, and designs discussed below are available for simple-cycle combustion turbine power generators.

- **Combustion Turbine Design**

CO_2 is a product of combustion of fuel containing carbon, which is inherent in any power generation technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, there is no technology available that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place.

Reducing the amount of CO_2 generated by a fuel-burning power plant per unit of power produced can be accomplished by reducing the amount of fuel combusted to meet the plant's required power output. This result is obtained by using efficient combustion technologies.

In addition to the high-efficiency primary components of a combustion turbine, there are a number of other design features employed within the turbine and ongoing operational practices that can be implemented to maintain and improve the overall efficiency of the machine. These additional features include those summarized below.

- **Evaporative Inlet Air Cooling**

Evaporative inlet air cooling is utilized during periods of warm to hot ambient air conditions. This technology uses the water evaporation process to lower the temperature of the inlet air thus increasing its density. This process results in a higher mass flow rate of the inlet air into the compressor section of the turbine and a resultant increase in power production from the combustion turbine. This process allows the combustion turbine to operate in a more efficient manner and restores some of the generating capacity that would normally be lost on warm to hot days.

- **Periodic Combustor Module Maintenance**

Regularly scheduled maintenance programs are recommended by manufacturers of modern combustion turbines. These maintenance programs are important for the reliable operation of the unit, as well as to maintain high efficiency. As the combustion turbine is operated over time, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major inspections. The following are further clarifications of what typically occurs during the various inspections:

Combustion Inspections
Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to optimize efficient low-emission operation.

Hot Gas Path Inspections
The inspector visually inspects the tiles on the inside of the combustor, the transition piece and the first stage vanes. A mirror is typically used to check the first stage blades. The other turbine and compressor stages can be observed by borescope.

Major Inspections
For major inspections every 16,000-24,000 hours of operation, the burner section is lifted off in one piece and inspected.

- **Reduction in Heat Loss**

Modern combustion turbines have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To reduce heat loss from the combustion turbine and protect the personnel and equipment around the machine, insulation blankets are applied to the combustion turbine casing. These blankets reduce the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.

- **Fuel Preheating**

The combustion turbine being considered for this facility is designed to operate with a fuel preheater in order to raise the temperature of the natural gas fuel supply to the combustion turbine. By raising the temperature of the fuel it helps to keep liquids from condensing out of the gas supply as it is introduced into the combustion turbine. This helps to improve the long-term reliability of the combustion turbine and reduces the amount of maintenance that would be required on the turbine as a result.

This process also improves the efficiency of the combustion turbine since it provides a steady state temperature for the gas supply to the combustion turbine as well as adding thermal energy to the combustion process.

- **Instrumentation and Controls**

Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital-type and is supplied with the combustion turbine. The turbine control system controls all aspects of the turbine's operation, including the fuel feed and burner operations, to achieve efficient low-emission combustion. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

5.1.2 Step 2: Eliminate Technically Infeasible Control Options

Carbon Capture and Storage (CCS)

When evaluating the feasibility of CCS, unlike any other control option, the feasibility of three requisite components must be evaluated: capture; compression and transport; and sequestration. The integration of these three components as well as the legal issues associated with CCS must also be included in its feasibility evaluation.

- **CO_2 Capture**

Capturing CO_2 is a technology that has not been applied at full scale to power plants. CO_2 gas separation technologies have been developed and employed in the industrial sector (e.g., petroleum refining and natural gas purification) for more than seventy years.[14] Also, CO_2 capture on a small scale has been happening for many years in the petroleum and industrial chemical industry. However, capturing CO_2 on the commercial scale of a power plant has never been performed, in the U.S. or abroad. There are various pilot scale and demonstration projects either already underway or soon-to-be in operation that are testing technologies that could one day be used at this scale. Several of these projects are listed in Table 5-1.

There are several methods to remove CO_2 from flue gas that are being developed and demonstrated at various capacities. The most studied post-combustion CO_2 removal processes to date employ reagents or sorbents that include the following: ammonia, monoethanolamine (MEA) or other amine-based reagents, and various solid sorbents.

Amine-based systems are the subject of intense study for utility application. However, amine-based reagents are in the early stages of development for use in electric generating units.[15] The amount of energy required to regenerate the CO_2 presents a challenge to commercial viability of such processes. In addition, many of these reagents can be impacted by exposure to compounds found in flue gas, such as oxygen, trace concentrations (10-20 ppm) of SO_2, and NO_x.

[14] http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf

[15] These other amine compounds, dry sorbents, and ammonia, as well as special-purpose compounds are presently being developed with DOE/NETL and private industry funding.

Several suppliers are developing amine-based systems for utility application by extrapolating designs from small-scale industrial applications. Table 5-1 presents a partial summary of projects either completed or in progress that entail testing of pilot plant and demonstration equipment.

TABLE 5-1 PARTIAL LIST OF COMPLETED/IN-PROGRESS POST-COMBUSTION CO2 PILOT-PLANT AND DEMONSTRATION TESTS

Commercial Supplier	Reagent	Location	Experience
Alstom	Advanced amine technology	Dow Chemical, S. Charleston, W. VA.	2 MW pilot plant started in Sept. 2009, for 2 year term.
Alstom	Ammonia (chilled)	AEP Mountaineer Plant, New Haven, WV	30 MW unit operated from Sept. 2009-May 2011
Siemens	Amino acid	E. On Staudinger Facility, Germany	1 MW pilot plant operating since Sept. 2009
Mitsubishi Heavy Industries	Advanced amine technology	Plant Barry, Mobile, AL	25 MW demonstration of CO_2 capture (2011) and sequestration (2012)
ADA-ES	Advanced amine sorbent technology	Plant Miller, Quinton, AL	1 MW demonstration of CO_2 capture (2014)

MEA-based processes are being evaluated including the Fluor ECONAMINE FG+ process, which uses a special inhibitor to resist corrosion and degradation from the oxygen. Alstom is exploring an amine-based process with Dow Chemical Company. Also, as shown in Table 5-1, Mitsubishi Heavy Industries and Southern Company are demonstrating a process using proprietary KS-1, developed by Mitsubishi and Kansai Electric Power Company.

Amine-based processes are not the only post-combustion CO_2 capture option. Siemens is developing an amino acid-based process (Jockenhoevel, 2008), and Alstom is demonstrating an ammonia-based process. Furthermore, amine-based processes do not necessarily have to utilize a liquid amine. ADA-ES, Inc., is finishing construction on a post-combustion carbon capture process that utilizes a solid amine-based sorbent. Alabama Power Plant Miller is serving as the host site for this project.

Significantly, all of these research projects and demonstration applications are pre-commercial – that is, they are not proven to deliver reliable, continuous CO_2 removal for utility scale applications at this time. EPA has acknowledged that this technology is not ready to be implemented on commercial-scale natural gas power plants. *See* "PSD and Title V Permitting Guidance for Greenhouse Gases," 2011.

- **CO_2 Compression and Transport**

After CO_2 is captured, it must be compressed "from near atmospheric pressure to a pressure between 1,500 and 2,200 psia in order to be transported via pipeline and then injected into an underground storage site."[16] Compressing CO_2 is energy intensive and expensive. The Department of Energy (DOE) National Energy Technology Laboratory (NETL) is working to develop concepts for large-scale CO_2 compression that will reduce the auxiliary power requirements and capital cost. NETL is evaluating various compression concepts using computational fluid dynamics and laboratory testing that will lead to developing prototypes and field testing. Their research efforts include "development of intra-stage versus inter-stage cooling; fundamental thermodynamic studies to determine whether compression in a liquid or gaseous state is more cost-effective; and development of a novel method of compression based on supersonic shock wave technology."[17]

Some pipelines exist today that transport supercritical CO_2. Since the 1970s, CO_2 has been transported in pipelines to oil fields for use in enhanced oil recovery (EOR). Before CCS can become widespread on power plants, an extensive CO_2 pipeline network will need to be created. Currently, there are only approximately 4,000 miles of these pipelines in the U.S., however, not all power plants are located on the existing CO_2 pipelines or near the location of geologic sinks for sequestration.[18] There will be a need for more pipeline capacity to transport the large volumes of CO_2 produced from power plants.

The CO_2 transported for use in EOR operations has historically been from the steady state production of natural geologic deposits and not from CO_2 captured at power plants. Compression and transportation operations could be affected by the unsteady flow of CO_2 sourced by power plants. See more on this issue in the "Integration" discussion below.

- **CO_2 Sequestration**

CO_2 sequestration is the third-step of the CCS process. It is the injection and long-term storage of CO_2 in geologic formations such as deep saline reservoirs, oil and gas reservoirs, and unmineable coal seams. These are geologic structures that have stored crude oil, natural gas, brine, and geologic CO_2 over millions of years; however, sequestration of commercial volumes of CO_2 produced by a power plant has not progressed beyond the research and development phase.

[16] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf
[17] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf
[18] http://www.sseb.org/wp-content/uploads/2010/05/pipeline.pdf

CO_2 Sequestration: Saline Formations

DOE has estimated that the U.S. could potentially store more than 12 trillion tons of CO_2 in deep saline formations.[19] Sustained injection operations and monitoring of CO_2 in saline formations in the U.S. has not progressed beyond the research and development phase. In Algeria and the North Sea, commercial scale CO_2 sequestration is taking place but not with CO_2 captured from a power plant. Table 5-2 lists various saline sequestration projects around the world.

TABLE 5-2 COMMERCIAL SCALE INJECTION PROJECTS

Owner/Operator	Location	Amount Sequestered
In-Salah (a joint venture of Sonartrach, BP, and Statoil)	Algeria in North Africa	1 million ton/year since 2004; Source: natural gas upgrading operations
Statoil (Norwegian oil company)	Utsira Sand, saline formation under the North Sea associated with the Sleipner West Heimedel gas reservoir	Approximately 1 million tons/year; equivalent to the output of a 150 MW coal-fired power plant; Source: natural gas upgrading operations
Southeast Regional Carbon Sequestration Partnership	Cranfield storage site in Mississippi	Approximately 100,000 tons/month (over 6.6 million tons since 2010); Source: Jackson Dome geologic source
Midwest Regional Carbon Sequestration Partnership	Mt. Simon Sandstone formation in Illinois	Approximately 400,000 tons since 2011; Source: ethanol plant

Southern is and has been involved in CO_2 saline sequestration research projects both on its own and as part of the Southeast Regional Carbon Sequestration Partnership (SECARB). Below are descriptions of these projects:

Plant Daniel Pilot Injection Project: This project was conducted by SECARB and involved drilling an injection well and an observation well into the Tuscaloosa Formation in South Mississippi at Plant Daniel. Approximately 3,000 tons of CO_2 were injected into a saline formation approximately 8,500 ft underground. The injection was completed in the fall of 2008 and monitoring was completed in 2010. The project included successful site characterization, permitting, injection operations, and monitoring of the CO_2 in the subsurface.

Plant Barry Anthropogenic CCS Demo/SECARB Phase III: Southern Company has been operating a 25 MW slip stream amine capture plant at Plant Barry since June 2011. Injection operations began in 2012. The project will provide CO_2 for the DOE regional sequestration partnership SECARB phase 3 large volume sequestration demonstration project. The SECARB project includes drilling two injection wells and two observation wells into the Paluxy saline formation located geologically above the Citronelle Oil Field in South Alabama. The project will inject 100,000-150,000 tons of CO_2 per year for up to three years with monitoring for three to

[19] http://www.fossil.energy.gov/programs/sequestration/geologic/

four additional years. The project also includes construction and operation of a twelve mile pipeline that will connect Plant Barry to the injection site. The project will confirm effective monitoring and verification protocols for geologic sequestration, address regulatory and permitting issues, and cultivate public education and outreach internally and externally. It is also one of the first projects in the world to study the integration of CO_2 capture operations at a coal plant with pipeline transportation and saline reservoir injection.

CO_2 Sequestration: Oil and Gas Reservoirs: For years, CO_2 has been used in EOR and enhanced gas recovery. In this process, CO_2 is pumped into an oil or gas reservoir to push out the product. During this process, some CO_2 is trapped in the reservoir. The U.S. is the world leader in EOR technology and uses over 32 million tons of CO_2 for this purpose.[20] The CO_2 used in EOR operations has historically been from the steady state production of natural geologic deposits and not from CO_2 captured at power plants. EOR operations can be affected by the variability and purity of the CO_2 sourced by power plants.

EOR is not available in all areas of the U.S. so it cannot be the answer for CO_2 sequestration for all power plants.

CO_2 Sequestration: Coal Seams: Coal seams (a.k.a., coal beds) contain large amounts of methane-rich gas that can be recovered by depressurizing the seam which can be done by injecting CO_2 into the formation. According to DOE, tests have shown the adsorption rate for CO_2 to be twice that of methane, "giving it the potential to efficiently displace methane and remain stored in the bed." However DOE also acknowledges that the "CO_2 recovery of coal-bed methane has been demonstrated in limited field tests, but much more work is necessary to understand and optimize the process."[21]

Southern Company participated in a SECARB project that evaluated the feasibility of combining carbon sequestration and enhanced recovery of coal bed methane. This project, the Black Warrior Basin Coal Seam Pilot Injection Project, injected 240 tons of CO_2 into coal seams at depths ranging from 940 feet to 1,800 feet. This project began in 2009 with the injection operations finalized in 2010. Monitoring will continue for several years to evaluate the methane recovery potential from the injection.

- **Integration**

CO_2 capture, transport, and sequestration have never before been integrated at commercial scale on a power plant. The integration of these processes on a power plant could result in operational issues and other unknowns. Problems could result from load fluctuations, outages, and CO_2 purity. Also, the reliability of the host generating unit could be affected by problems associated with the CCS processes.

[20] http://www.fossil.energy.gov/programs/sequestration/geologic/
[21] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf

Integration: Loading: Power plants do not run consistently; their load fluctuates as needed to meet electricity demand which may affect the CCS equipment. EOR operations historically have been supplied with CO_2 from some steady source such as a natural geologic deposit of CO_2 or from a natural gas purification process. The knowledge available on CO_2 sequestration is mostly from EOR operations. Therefore, it is unknown how the processes of CO_2 sequestration could be impacted by inconsistent CO_2 flow.

Integration: Outages: Power plants experience planned and forced outages. During these outages, the CCS processes would be suspended. It is unknown how this suspension will affect the injection operations and equipment.

Integration: CO_2 Purity: The CO_2 from power plants may not be the same as the CO_2 that is produced from natural geologic deposits or from natural gas purification processes. It is unknown how streams of varying purity CO_2 will be able to be integrated into the same pipeline network.

Integration: Reliability: Reliability of a CCS system including the host power plant could be affected by problems arising in each CCS process. Because CO_2 capture, transport, and sequestration have not been integrated on a power plant before, it is unknown how the three processes will interact with each other. For example, it is unknown how problems at the capture unit will affect the injection sequestration operations. If the capture unit goes down and the CO_2 injection process stops, there could be implications to the geologic sequestration formation. If the CO_2 cannot be injected, the host power plant may not be able to run unless it is able to emit its CO_2 emissions while the problems in the CCS processes are addressed. Problems in one CCS process will likely affect the operations of another process and thus impact the reliability of the system and potentially the ability of the host power plant to operate.

Southern Company is involved in several demonstration projects that will provide some experience with the integration of CCS' three-step process (i.e., capture, compression and transport, sequestration) on a commercial scale power plant. As these projects show, CCS is currently far from a demonstrated CO_2 control technology at commercial scale on a power generation unit and requires much additional study. As mentioned above, Southern Company's Plant Barry Anthropogenic CCS Demo/SECARB Phase III project, which began integrated operation in 2012, is one of the first projects in the world to study the integration of CO_2 capture operations at a coal plant with pipeline transportation and saline reservoir injection. However, this project is not commercial scale and the operation of the generating units is not dependent on the operation of the capture system. Also, Southern Company plans to gain experience with the integration of CO_2 capture operations with pipeline transport and EOR with Mississippi Power's Kemper County Energy Facility beginning in 2014. The Kemper Project is a DOE Clean Coal Power Initiative demonstration project. It is an air-blown Integrated Gasification Combined Cycle (IGCC) demonstration project that will allow for pre-combustion capture of 65 percent of the CO_2 emissions. The applicability of the experience gained at the Kemper project once it begins operations is likely limited for many projects, because IGCC with integrated pre-combustion CCS is significantly different than natural gas or pulverized coal with post-combustion add-on CCS technology. Also, the applicability of the Kemper project demonstration to other projects in the future will depend heavily on location, as the captured CO_2 from this project will be sold for EOR. Years of operation of the Kemper project will be required to gain experience for future projects.

- **CCS Legal Issues**

There are legal issues associated with CCS that need to be addressed before CCS can become widespread. These issues include pore-space ownership, long-term liability, and CO_2 pipeline related issues. Some States have enacted laws governing these issues, but they vary. This is a problem for projects that operate in states without such laws and for projects that cover multiple states.

Also, CCS is different from other control technologies because, if required for compliance, responsibility may need to be shared between multiple parties, not just the power plant owner/operator. For example, if EOR is used to sequester CO_2, the power generator will likely have to enter into a contract with a third party to transport the CO_2 and demonstrate sequestration. Under such arrangements where the power plant is dependent on a third party for compliance, there are always risks of contract breeches, dissolution of the contract parties, or other issues that cannot be foreseen that could put the ability of the power plant to meet electricity demand at risk.

- **CCS Conclusion**

As discussed above, CCS has potential to reduce CO_2 emissions through post combustion control technology but, currently, is not a technically feasible technology to be applied to power plants for controlling CO_2 emissions and is therefore dismissed from further consideration in this BACT analysis. Progress needs to be made on each step of the CCS process to ensure that it will work on a commercial scale with the characteristics of a power plant, and the integration of the CCS processes on a commercial scale power plant has yet to be accomplished. As EPA states in its GHG BACT Guidance, "CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type…Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations".[22]

Though SPC believes the technical infeasibility of CCS for control of CO_2 from power plant operations has been thoroughly explained above, we recognize that other recent GHG applications have included an economic analysis of CCS. The average cost of removal per ton of CO_2 calculated for CCS by other applicants proposing similar technologies using the Department of Energy/National Energy Technology Laboratory cost estimation procedure has been in the range of \$83.53/ton to \$92.65/ton removed and has been deemed economically

[22] http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf (pgs. 35-36)

infeasible in all cases. These estimates were all performed for sources other than simple-cycle combustion turbines.

The addition of CCS to a simple-cycle combustion turbine would require the addition of:

- A large heat exchanger in order to cool the turbine exhaust in order to utilize an amine-based CO_2 removal process.
- Process equipment required to perform the amine-based CO_2 removal from the stack gas as well as CO_2 stripping from the amine solution
- Compressor equipment to pressurize the removed CO_2

No cost estimate information exists for a CCS facility located at a simple-cycle facility and so no detailed cost analysis of a CCS installation at the NPEGP can be provided. As a surrogate, the high-end of the combined-cycle cost estimation range will be utilized for this analysis. In reality, the cost of installing such a system at a simple-cycle unit would be much higher (possibly an order of magnitude higher) on a $/$CO_2$-ton-removed basis compared to a combined-cycle unit due to the difference characteristics of the exhaust for the two types of combustion turbines and the much lower capacity factor of a peaking unit as compared to a combined-cycle facility.

5.1.3 Step 3: Rank Remaining Control Options

As discussed above, there are no technically feasible post combustion options for GHG removal on a simple-cycle system at this time. A well-designed efficient unit is the only remaining control option for GHG emissions.

5.1.4 Step 4: Evaluate Remaining Options

A well-designed efficient unit is the only remaining control option for the simple-cycle combustion turbine. Since all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1.2.2. of this application are being incorporated into this project, a comparison of the energy, environmental, and economic impacts of the identified efficiency designs and practices is not necessary for this application.

5.1.5 Step 5: Selection of BACT

SPC's simple-cycle design incorporates elements which will result in reliable and efficient long term operation for the expected operational profile of the unit. Significant design criteria include the gas turbine efficiency and its impact on the overall simple-cycle plant efficiency. The selection of the specific gas turbine to be incorporated in a project is based upon unit efficiency, capacity needs, expected operating profile, and project economics. SPC conducted a diligent review of the various manufacturers and the different variants of combustion turbine that would normally be considered for an installation such as NPEGP. The utilization of a high efficiency gas turbine along with an overall efficient and economic plant design is considered BACT for natural gas-fired simple-cycle applications.

SPC proposes the following energy efficient design for the proposed simple-cycle combustion unit as BACT for this project:

- Efficient Combustion Turbine Processes, Practices, and Designs
    - Efficient turbine design
    - Evaporative inlet air cooling
    - Periodic turbine combustor module maintenance
    - Reduction in heat loss
    - Instrumentation and controls

To complete the BACT process, an enforceable emission limit must be established if feasible. Such a limit should be able to be "met on a continual basis at all levels of operation," "demonstrate protection of applicable short term ambient standards," and "be enforceable as a practical matter."[23]

To set an enforceable emission limit, the unique characteristics of GHG emissions must be considered. In its final Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, EPA states that the "common physical properties relevant to the climate change problem shared by the six greenhouse gases include the fact that they are long-lived in the atmosphere."[24] In EPA's definition of "long-lived" it emphasizes that GHGs are well mixed in the atmosphere and therefore emissions from one source are not necessarily going to impact the local environment: "the gas has a lifetime in the atmosphere sufficient to become globally well mixed throughout the entire atmosphere…" [25] Furthermore, there are no established short term (or long term) ambient standards for GHGs.

SPC proposes the limit be set in tons-per-year of CO_2e. This approach is consistent with the nature of GHGs (long-lived gases that only present a potential environmental concern via their contribution to total, long-term atmospheric concentrations). A tons-per-year limit is also consistent with EPA's use of this measure in its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule and its Mandatory GHG Reporting Program. As mentioned above, EPA requires reporting of annual tons of CO_2e emissions and so an annual CO_2e ton limit would be straightforwardly enforceable as a practical matter. Therefore, a GHG BACT limit for the natural gas-fired simple-cycle turbine of 319,158 short tons of CO_2e per rolling 12-month period is proposed (calculated each month as the summation of the emissions from the previous twelve months). A Part 75 compliant monitoring system will be utilized to determine the actual CO_2 portion of the GHG emissions. Heat input and emission factors from the GHG Mandatory Reporting Rule will be used to determine the CH_4 and N_2O portions (including Global Warming Potentials of 25 for CH_4 and 298 for N_2O). This annual limit will take

[23] *New Source Review Workshop Manual*, DRAFT, October 1990, B.V.
[24] 74 Fed. Reg. 66517
[25] Id.

into account all GHG emissions from the simple-cycle unit. The tpy emission calculations are included at the end of Section 3.0 of this application in Table 3-2.

In order to account for the continued operation of the unit in an energy efficient manner, SPC proposes an output-based emission limit of 1,316 lb CO_2/MW-hr (gross) as determined by an annual performance test using calibrated plant instrumentation for the CTG. Note that this rate reflects the CTG's "gross" power production, meaning the denominator is the total amount of power produced by the CTG, and does not exclude auxiliary load consumed by operation of the CTG. The emission calculations for the proposed lb CO_2/MW-hr (gross) limit are included in Table 5-4 and are described below. Results from the test will be corrected back to the 95^0 F conditions using the manufacturer curves

The proposed lb CO_2/MW-hr (gross) efficiency limit is based on design heat rate data provided by the equipment manufacturer and estimated CO_2 emissions calculated using 40 CFR Part 75, Appendix G, Equation G-4. Southern, in order to establish a proposed emission limit for the CTG, started with the turbine's design gross heat rate representative of the 100% load case at 95^0 F ambient conditions and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The following compliance margins are added to the base heat rate:

- A 5% design margin reflecting the possibility that the constructed facility will not be able to achieve the design efficiency
- A 6% performance margin reflecting efficiency losses due to gas turbine degradation prior to maintenance overhauls.

Design and construction of a simple-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which may vary once installed at the site. As a consequence, a design margin of 5% to address such items as equipment underperformance and short-term degradation is needed as based on typical equipment guarantees for combustion turbine technology.

To establish an enforceable BACT condition that can be achieved over the life of the facility, the permit limit must also account for anticipated degradation of the equipment over time between regular maintenance cycles. The manufacturer's degradation curves project an anticipated degradation rate of 5% within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbine. Therefore, Southern proposes that, for purposes of deriving an enforceable lb CO_2/MW-hr (gross) BACT limitation, gas turbine degradation may reasonably be estimated at 6%.

SPC is proposing the following BACT limits for the Natural Gas Simple-cycle Unit:

TABLE 5-3 BACT SUMMARY

Unit	Tons of CO_2e per year	Output Based Emission Limit ($lb\ CO_2/MWh$ gross)
Siemens Model 5F	319,158	1,316

The calculation of the lb CO_2/MWh value is provided on Table 5-4.

On January 8, 2014, EPA published in the Federal Register its re-proposal of New Source Performance Standard (NSPS), Subpart TTTT – or in the alternative, revisions to Subparts KKKK and Da – which would establish limits for CO_2 emissions from certain new power plants. The proposed rule would apply to new fossil-fuel-fired steam electric generating units that sell more than one-third of their potential output and more than 219,000 MWh net electrical output to the grid on an annual basis. As a result, NSPS Subpart TTTT, if finalized as proposed, would not be applicable to this simple-cycle combustion turbine project due to the 2,500 hour limit on annual operations, and need not be factored into the BACT analysis.

SPC performed a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) for natural gas fired simple-cycle combustion turbine generators and found a limited number of entries which address BACT for GHG emissions. These facilities are: Basin Electric-Lonesome Creek, Basin Electric-Pioneer Generating Station, Montana-Dakota-R.M. Heskett Station and Pio Pico Energy Center.

Although not currently included in the RBLC, the GHG permit applications/permits from the following facilities were also included in the BACT analysis for comparison purposes: Guadalupe Power Partners-Guadalupe Generating Station, Cheyenne Prairie Generating Station, El Paso Electric-Montana Power Station, NRG Texas Power-Cedar Bayou 5, NRG Texas Power-S.R. Bertron 5, Golden Spread Electric Co-Op-Antelope Station, Golden Spread Electric Co-Op-Floydada Station and Invenergy-Ector County Energy Center.

Table 5-5 below presents a summary of the type(s) of units at the facilities listed in the RBLC and their proposed or permitted BACT limits.

Table 5-6 below presents a summary of the type(s) of units at the facilities not yet listed in RBLC and their proposed or permitted BACT limits.

Table 5-4
GHG Emission Calculations - Calculation of Design Heat Rate and Output Limits for Siemens F5 Simple-Cycle Turbine
Nacogdoches Power Electric Generating Plant

100% Load, 95F Ambient Temperature, Without Evaporative Cooling

	Gross Basis	
Base Heat Rate:	**9,951**	Btu/kWh (HHV)
Design Margin:	5.0%	
Performance Margin:	6.0%	
Adjusted Base Heat Rate with Compliance Margins:	**11,075**	Btu/kWh (HHV)

EPN	Base Heat Rate (Btu/kWhr)	Electrical Output Basis	Heat Input Required to Produce 1 MW (MMBtu/MWhr)	Pollutant	Emission Factor (lb/MMBtu)	lb GHG/MWhr[1]
CTG1-STK	11,075	Gross	11.07	CO_2	118.86	1,316.34

Note
1. CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4
$W_{CO2} = (F_c \times H \times U_f \text{ X } MW_{CO2})/2000$
W_{CO2} = CO_2 emitted from combustion, tons/yr
F_c = Carbon based F-factor,1040 scf/MMBtu
H = Heat Input (MMBtu/yr)
U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 ^oF
MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lbmole

Table 5-5
Proposed Natural Gas-Fired Combustion Turbine GHG BACT Limits - Units Listed in RBLC
Nacogdoches Power Electric Generating Plant

Company, Facility Name	Permit Date	Permit Number	Plant Size	Location	Plant Type	Type(s) of Units	GHG Emission Limit	Heat Rate Limit	Averaging Period	Notes
Basin Electric, Lonesome Creek	09/16/13	PTC 13049	45 MW each	McKenzie-ND	Three natural gas-fired simple cycle turbines in peaking service	GE LM6000 PF Sprint	220,122 TPY CO2e	412 MMBtu/hr (each)	12-month rolling mass total	Control Method: High efficiency turbines
Basin Electric, Pioneer Generating Station	05/14/13	PTC 13037	45 MW each	Williams-ND	Three natural gas-fired simple cycle turbines in peaking service	GE LM6000 PF Sprint	243,147 TPY CO2e	451 MMBtu/hr (each)	12-month rolling mass total	Combusting natural gas with HHV of 1200 Btu/scf.
Montana-Dakota, R.M. Heskett Station	02/22/13	PTC 13016		Morton-ND	One natural gas-fired simple cycle turbine in peaking service	GE 7EA (PG 7121)	413,198 TPY CO2e	986 MMBtu/hr	12-month rolling mass total	
Pio Pico, Pio Pico Energy Center	11/19/2012	SD 11-01	100 MW each	Otay Mesa-CA	Three natural gas-fired simple cycle turbines in peaking service	GE LMS100	1,328 lb/MWh CO2e		720-hr rolling operating hour avg.	Power purchase agreement not yet finalized. Facility won't be built until this occurs.

Table 5-6
Proposed Natural Gas-Fired Combustion Turbine GHG BACT Limits - Units Not Listed in RBLC
Nacogdoches Power Electric Generating Plant

Company, Facility Name	Application Submitted Date	County-State	Plant Type	Type(s) of Units	Proposed GHG Emission Limit	Proposed Heat Rate Limit/Output-based limit	Averaging Period	Notes
Guadalupe Power Partners, Guadalupe Generating Station	11/13/12	Guadalupe-TX	Two natural gas-fired simple-cycle combustion turbines in peaking service	GE Model 7FA.03	511,429 TPY CO2e	11,121 Btu/kWh (gross, HHV)	TPY limit: 12-month rolling avg. Heat Rate Limit: Annual thermal efficiency test at base load and corrected to ISO conditions	Maximum of 2500 hours per year of operation
				GE Model 7FA.04	522,772 TPY CO2e	10,826 Btu/kWh (gross, HHV)	TPY limit: 12-month rolling avg. Heat Rate Limit: Annual thermal efficiency test at base load and corrected to ISO conditions	Maximum of 2500 hours per year of operation
				GE Model 7FA.05	601,520 TPY CO2e	10,673 Btu/kWh (gross, HHV)	TPY limit: 12-month rolling avg. Heat Rate Limit: Annual thermal efficiency test at base load and corrected to ISO conditions	Maximum of 2500 hours per year of operation
				Siemens-Westinghouse (SW) 5000F(5)	681,839 TPY CO2e	11,456 Btu/kWh (gross, HHV)	TPY limit: 12-month rolling avg. Heat Rate Limit: Annual thermal efficiency test at base load and corrected to ISO conditions	Maximum of 2500 hours per year of operation
Cheyenne Prairie Generating Station	Permit issued: 9/27/12	Laramie-WY	Three natural gas-fired simple-cycle combustion turbines in peaking service	LM6000 PF Sprint	187,318 TPY CO2e (each)	1,600 lb CO2e/MWh (gross)	TPY and Output-based limits: 365-day rolling avg.	
El Paso Electric, Montana Power Station	4/20/2012	El Paso-TX	Four natural gas-fired simple-cycle combustion turbines in peaking service	GE LMS100	227,840 TPY CO2e (each)	1,194 lb CO2/MWh (net)	TPY limit: 365-day rolling avg. Output-based limit: 12-rolling-month avg.	Includes MSS emissions, TPY limits listed are metric tons. Gross heat rate is based on base load at ISO conditions.
NRG Texas Power, Cedar Bayou 5	11/26/2012	Chambers-TX	Two natural gas-fired simple-cycle combustion turbines in peaking service	SW F5, MHI 501GAC or GE 7FA.05	GE 7FA.05: 1,203,838 TPY CO2e Siemens F(5): 1,344,347 TPY CO2e MHI 501 GAC: 1,468,007 TPY CO2e	11,500 Btu/kWh (net)	TPY limit: 12-month rolling avg.	
NRG Texas Power, S.R. Bertron 5	11/26/2012	Harris-TX	Two natural gas-fired simple-cycle combustion turbines in peaking service	SW F5, MHI 501GAC or GE 7FA.05	GE 7FA.05: 1,203,838 TPY CO2e Siemens F(5): 1,344,347 TPY CO2e MHI 501 GAC: 1,468,007 TPY CO2e	11,500 Btu/kWh (net)	TPY limit: 12-month rolling avg.	
Golden Spread Electric Co-op, Antelope Station	2/1/2013	Hale-TX	One natural gas-fired simple-cycle combustion turbine in peaking service	GE 7FA.05	538,754 TPY CO2e 237,767 lb/hr CO2e	1,217 lb CO2e/MWh (gross) at maximum load 1,514 lb CO2e/MWh (gross) at 50-100% load	Heat Rate: 12-rolling month avg.	
Golden Spread Electric Co-op, Floydada Station	2/1/2013	Floyd-TX	One natural gas-fired simple-cycle combustion turbine in peaking service	GE 7FA.05	538,754 TPY CO2e 237,767 lb/hr CO2e	1,217 lb CO2e/MWh (gross) at maximum load 1,514 lb CO2e/MWh (gross) at 50-100% load		Note: This application has subsequently been withdrawn by the applicant.
Invenergy, Ector County Energy Center	6/26/2013	Ector-TX	Two natural gas-fired simple-cycle combustion turbines in peaking service	GE 7FA.03 or GE 7FA.05	283,681 TPY CO2e (each unit)	GE 7FA.03: H.R.: 12,038 Btu/kWh, and 1,431 lb CO2/MWh GE 7FA.05: H.R.: 11,324 Btu/kWh and 1,346 lb CO2/MWh	Output-based limit: 12-month rolling avg.	Output-based proposed limit and heat rate based on gross output and HHV.

Although there are differences in the combustion turbine designs proposed by each plant, as well as differences in the basis of the proposed limits (i.e. gross output basis vs. mass emission rate limits or not, etc.), the summary presented above demonstrates that the limits proposed by SPC for the NPEGP are comparable to recently issued permits.

Although the above facilities may be currently under construction, none of the power plants that have received GHG permits have yet begun operation. Therefore, long term compliance with their permit limits has not been demonstrated. The GHG BACT limits should meet the twin goals of allowing flexible operation of the simple-cycle unit as well as limiting mass emissions of GHGs to the atmosphere. Output-based limits have the desired effect of promoting operators to seek thermal efficiencies in their unit operations, resulting in increased electrical output for reduced GHG emissions and ton per year limits restrict the total mass emissions of GHG's into the atmosphere.

Therefore, SPC concludes that the combination of the ton per year and output-based limits presented in Table 5-3 are BACT for this project.

5.2 BACT FOR NATURAL-GAS-FIRED FUEL PREHEATER

Based on the lack of available steam or hot water to heat the incoming fuel supply for this project, a natural gas-fired fuel supply preheater will be installed as described in the combustion turbine section above. The fuel preheater will have a nominal rating of 2.75 MMBtu/hr and will be utilized to raise the temperature of the natural gas supplied to the simple-cycle unit. Raising the temperature of the fuel supply above the dew-point will reduce the chances of condensation being introduced into the combustor section of the combustion turbine. The fuel preheater will be utilized any time that the combustion turbine is in operation.

5.2.1 Step 1: Identify All Control Options

As with the simple-cycle unit, the options for controlling GHG emissions for the preheater can be divided into two categories: Post-Combustion and efficient combustion processes, practices, and designs.

Post-Combustion Options:

CCS was discussed in detail for the simple-cycle combustion turbine BACT analysis.

Efficient Combustion Options:

By sizing the fuel preheater components to be appropriate for their purposes, emissions are reduced by virtue of increased efficiency. For this project, the fuel preheater was sized appropriately to heat the fuel supply required by the gas turbine.

Furthermore, the use of natural gas fuel, which is the lowest carbon fuel available at NPEGP, will minimize formation of CO_2 from combustion of the fuel.

Good operating and maintenance practices for the fuel preheater will maintain turbine efficiency over time, thus reducing emissions. Operating and maintenance practices that will be implemented will include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintaining the proper air/fuel ratio so that sufficient oxygen is provided to provide complete combustion of the fuel while at the same time preventing introduction of more air than is necessary into the fuel preheater.

The fuel preheater is designed for a thermal energy efficiency of approximately 77%. The energy efficient design of the heater includes insulation to retain heat within the unit and a computerized process control system that will optimize the fuel/air mixture and limit excess air in the boiler, thus increasing efficiency and reducing emissions.

5.2.2 Step 2: Eliminate Infeasible Control Options

Carbon Capture and Storage - (CO_2)

CCS was discussed above for the simple-cycle combustion turbine, and it was determined that it is technically infeasible for application on a commercial scale power plant at this time. The same rationale holds true for the fuel preheater.

5.2.3 Step 3: Rank Remaining Control Options

As discussed above, the only potential post-combustion options for GHG removal are all technically infeasible for application on the fuel preheater at this time. This leaves efficient combustion, processes, practices, and designs as the only available control option.

5.2.4 Step 4: Evaluate Remaining Options

Efficient processes, practices, and design considerations are the only remaining control options for the fuel preheater.

5.2.5 Step 5: Selection of BACT

Based on this top-down analysis, Southern concludes that the use of natural gas as a low carbon fuel, good operating and maintenance practices, efficient design; and low annual capacity is BACT for the fuel preheater. With the limited annual operation of the fuel preheater, the total CO_2e emissions from it are no more than 0.13% of the total project emissions.

5.3 BACT FOR NATURAL GAS FUGITIVES

The proposed project will include natural gas piping components. These components are potential sources of methane and CO_2 emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points.

5.3.1 Step 1: Identify All Available Control Technologies

The following technologies were identified as potential control options for piping fugitives:

- Implementation of leak detection and repair (LDAR) program using a hand held analyzer.
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras
- Implementation of audio/visual/olfactory (AVO) leak detection program

5.3.2 Step 2: Eliminate Technically Infeasible Options

The use of instrument LDAR and remote sensing technologies are technically feasible. Since pipeline-quality natural gas is odorized with a small amount of mercaptan, an AVO leak detection program for natural gas piping components is also technically feasible.

5.3.3 Step 3: Rank Remaining Control Technologies

The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, sampling connections, and compressors and 30% for flanges.[26] Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges.[27] The U.S. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g). For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.[28]

The control options are ranked, based on the expected level of control and the practicability of the option, as follows with the highest ranked option first:

[26] *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, TCEQ, Oct. 2000*
[27] *Id.* at page 52
[28] *Id.* at page 52

1. AVO leak detection program.
2. LDAR program using a hand held analyzer.
3. Alternative monitoring using a remote sensing technology such as infrared cameras.

5.3.4 Step 4: Evaluate Remaining Options

The frequency of inspection and the low odor threshold of mercaptans in natural gas make AVO inspections an effective means of detecting leaking components in natural gas service. As discussed in Section 5.5.3, the predicted emission control efficiency is comparable to the LDAR programs using Method 21 portable analyzers.

5.3.5 Step 5: Selection of BACT

Due to the very low volatile organic compound (VOC) content of natural gas, the NPEGP will not be subject to any VOC leak detection programs by way of its State/PSD air permit, TCEQ Chapter 115 – Control of Air Pollution from Volatile Organic Compounds, New Source Performance Standards (40 CFR Part 60), National Emission Standard for Hazardous Air Pollutants (40 CFR Part 61); or National Emission Standard for Hazardous Air Pollutants for Source Categories (40 CFR Part 63). Therefore, any leak detection program implemented will be solely due to potential greenhouse emissions. Since the uncontrolled CO_2e emissions from the natural gas piping represent less than 0.1% of the total project CO_2e emissions, any emission control techniques applied to the piping fugitives will provide minimal CO_2e emission reductions. SPC therefore proposes no leak detection program as BACT for natural gas fugitives.

5.4 BACT FOR SF_6 INSULATED ELECTRICAL EQUIPMENT

5.4.1 Step 1: Identify All Available Control Technologies

One option for insulation of electrical equipment is the use of industry standard modern SF_6 technology, including leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems quickly, so that it can be addressed proactively in order to prevent further release of the gas.

One available alternative is to substitute another, non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 are addressed in the National Institute of Standards and Technology (NIST) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[29]

[29] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6,* NIST Technical Note 1425, Nov.1997.

5.4.2 Step 2: Eliminate Technically Infeasible Options

According to the report NIST Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications.[30] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is vastly superior in performance to the air and oil insulated equipment used prior to the development of SF_6-insulated equipment. The NIST report indicates that new alternatives to SF_6 are not yet ready, concluding that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore, use of a non-GHG substance in place of SF_6 is technically infeasible.

5.4.3 Step 3: Rank Remaining Control Technologies

The use of industry standard SF_6 technology with leak detection to limit fugitive emissions is the only remaining control technology that is technically feasible for this application.

5.4.4 Step 4: Evaluate Remaining Options

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

5.4.5 Step 5: Selection of BACT

Based on this top-down analysis, Southern concludes that using industry standard enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[31] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will identify potential fugitive SF_6 emissions problems quickly. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

[30] *Id.* at 28 – 29.

[31] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

6.0 OTHER PSD REQUIREMENTS

6.1 AIR QUALITY IMPACTS ANALYSIS

An air quality impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs.*[32]

An air quality impacts analysis for non-GHG emissions is being submitted with the State/PSD application submitted to the TCEQ.

6.2 GHG PRECONSTRUCTION MONITORING

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> *EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.*[33]

A pre-construction monitoring analysis for non-GHG emissions is being submitted with the State/PSD application submitted to the TCEQ.

6.3 ADDITIONAL IMPACTS ANALYSIS

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions*

[32] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* at 47-49.
[33] *Id.* at 48.

contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.[34]

A PSD additional impacts analysis for non-GHG emissions is being submitted with the State/PSD application submitted to the TCEQ.

[34] *Id.* at 48.

7.0 PROPOSED GHG MONITORING PROVISIONS

SPC proposes to utilize the equation below and records of hourly heat input to calculate hourly CO_2 mass emissions as specified in 40 CFR 75, Appendix G. SPC will use the carbon-based F-factor of 1040 scf/MMBtu for natural gas.

The formula used for calculating CO_2 tons/hour is as follows. This is equationG-4 in 40 CFR 75, Appendix G, Section 2.3:

$$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2{,}000$$

Where:

W_{CO2} = CO_2 *emitted from combustion, tons/hr*

F_c = *Carbon based F-factor (1,040 scf/MMBtu for natural gas)*

H = *Hourly heat input in MMBtu*

U_f = *1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F, or 0.002597*

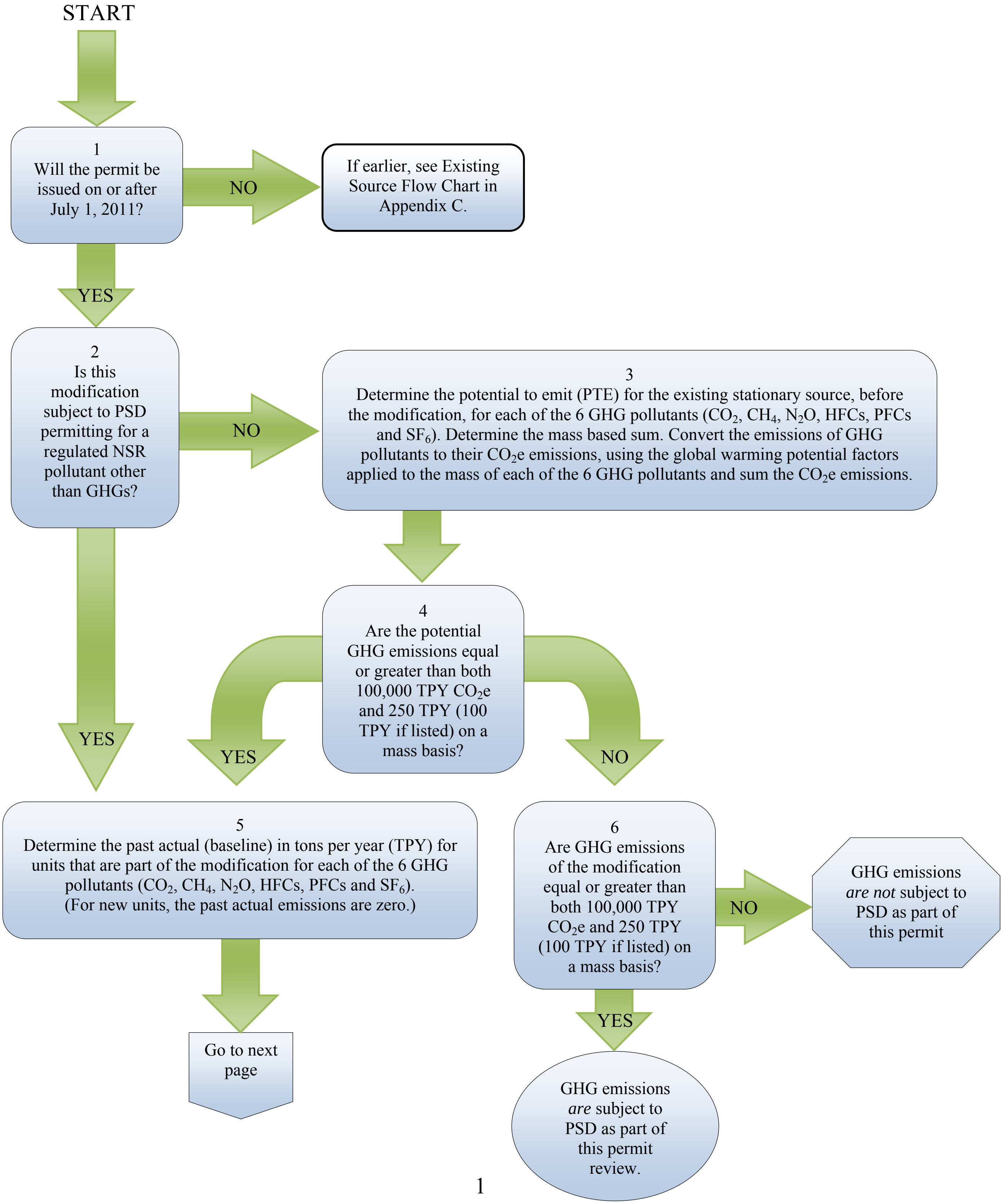
MW_{CO2} = *molecular weight of CO_2, 44.0 lb/lbmole*

This monitoring approach is consistent with the CO_2 reporting requirements of the GHG Mandatory Reporting Rule for Electricity Generation (40 CFR 98, Subpart D). Subpart D requires electric generating sources that report CO_2 emissions under 40 CFR 75 to report CO_2 under 40 CFR 98 by converting CO_2 tons reported under Part 75 to metric tons.

APPENDIX A

GHG PSD APPLICABILITY FLOWCHART – EXISTING SOURCES

GHG Applicability Flowchart – Modified Sources
(On or after July 1, 2011)



From prior page

7
For units that are part of the modification, determine the future projected actual emissions (or PTE) in TPY for each of the 6 GHG pollutants.

8
For each unit, determine the increase or decrease in mass emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions. (For new units that are not "replacement units," future actual emissions are equal to the PTE.)

9
For each unit, sum any increase or decrease in GHG emissions on a mass basis.

10
For all units that have mass emissions increase, sum the GHG emissions on a mass basis.

11
Is the sum of GHG mass emissions increase over zero TPY?

NO

GHG emissions *are not* subject to PSD as part of this permit review.

YES

12
For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO_2e number for each unit.

13
Sum the GHG emissions on a CO_2e basis for all units that have an emissions increase. (Emission decreases are not considered in this step.)

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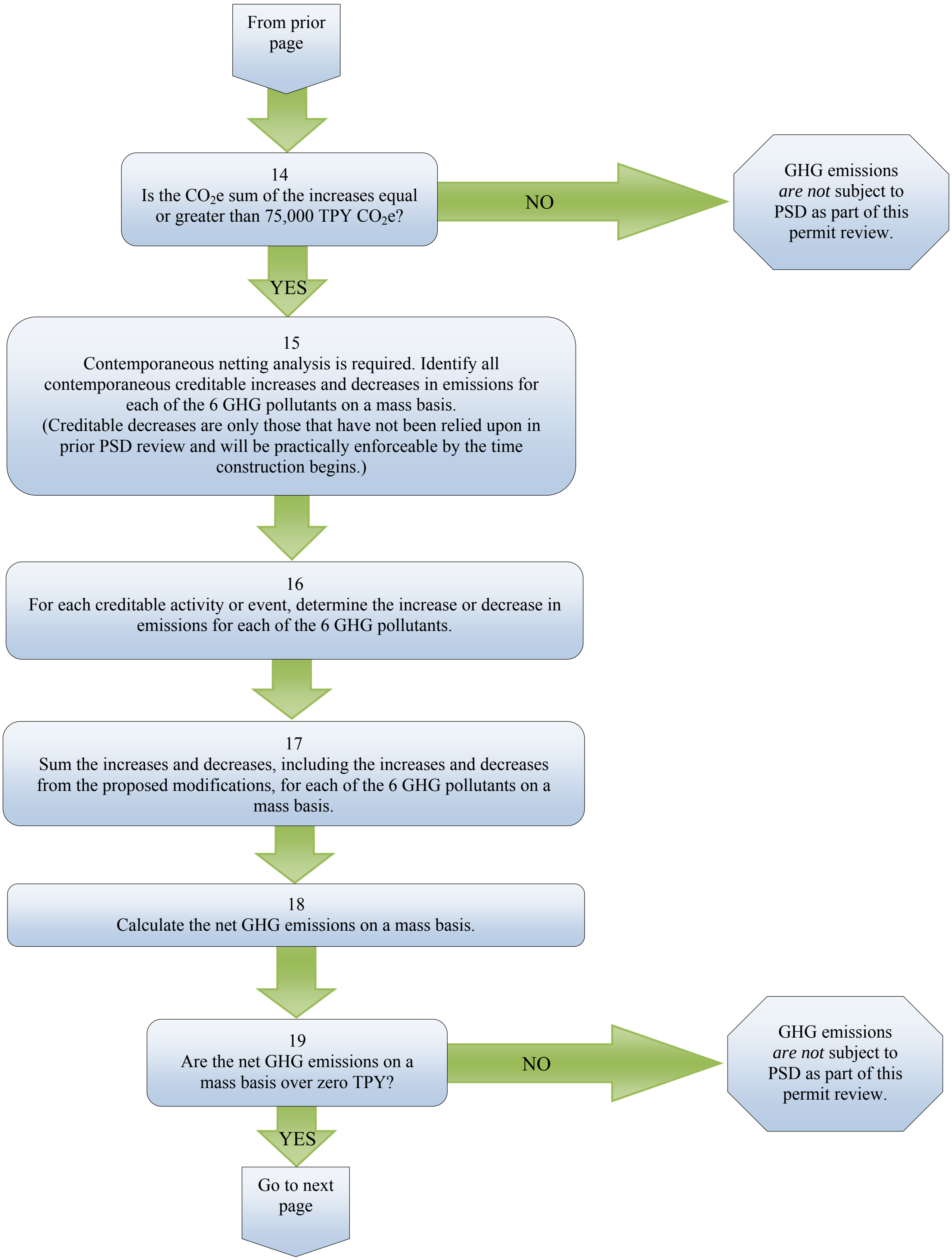
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14
Is the CO_2e sum of the increases equal or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
15
Contemporaneous netting analysis is required. Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis.
(Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.)
16
For each creditable activity or event, determine the increase or decrease in emissions for each of the 6 GHG pollutants.
17
Sum the increases and decreases, including the increases and decreases from the proposed modifications, for each of the 6 GHG pollutants on a mass basis.
18
Calculate the net GHG emissions on a mass basis.
19
Are the net GHG emissions on a mass basis over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
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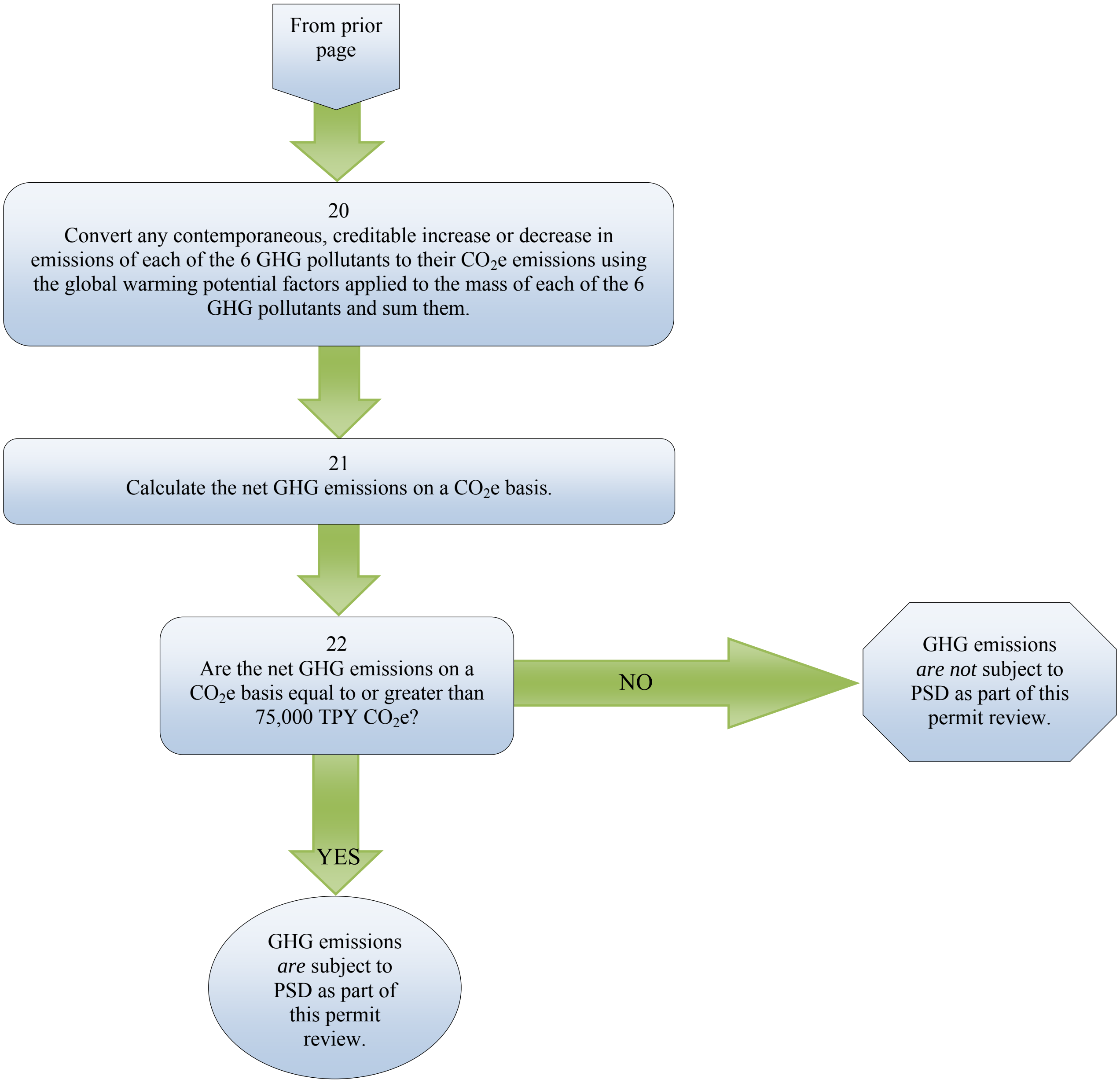
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20
Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them.
21
Calculate the net GHG emissions on a CO_2e basis.
22
Are the net GHG emissions on a CO_2e basis equal to or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.